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Pressure buildup due to CO_2 injection in brine aquifers

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Introduction

Maximum allowable injection rates of CO_2 are often identified as important bottlenecks in applied CCS chains. Injection rates are limited to ensure pressures do not exceed fracture pressures of reservoir formations. In this context, maximum injection rates of potential CO_2 storage sites are estimated using numerical reservoir simulators. Recently, Mathias et al. (2009; 2011) produced a semi-analytical solution for pressure-buildup estimation. However, derivation involved a number of simplifying assumptions including:

1) Negligible vertical pressure gradient.
2) Negligible capillary pressure.
3) Immiscible displacement.
4) Constant fluid properties.
5) Linear relative permeability.

This poster seeks to explore the implications of these assumptions by comparison of results from TOUGH2 ECO2N.

Approximate solution

$$p_D \approx \begin{cases} F_D(2/\gamma) - \frac{1}{2}\ln\left(\frac{x}{2\gamma}\right) - 1 + \frac{1}{\gamma}, & x \le 2\gamma \\ F_D(2/\gamma) - \left(\frac{x}{2\gamma}\right)^{1/2} + \frac{1}{\gamma}, & 2\gamma < x < 2/\gamma \\ F_D(x), & x \ge 2/\gamma \end{cases}$$

$$F_D(x) \approx \begin{cases} \frac{1}{2\gamma} E_1\left(\frac{\alpha x}{4\gamma}\right), & t_D < t_{cD} \\ \frac{2t_D}{\alpha r_{cD}^2} - \frac{1}{\gamma}\left[\frac{3}{4} - \frac{1}{2}\ln\left(\frac{r_{cD}^2}{x t_D}\right)\right] - \frac{(\gamma x - 2)t_D}{2\gamma r_{cD}^2}, & t_D > t_{cD} \end{cases}$$

$$t_D = \frac{M_0 t}{2\pi(1-S_r)\phi H r_w^2 \rho_o} \qquad \gamma = \frac{\mu_o}{k_r \mu_w} \qquad r_{cD} = \frac{r_c}{r_w}$$

$$p_D = \frac{2\pi H \rho_o k_r k (p - p_0)}{M_0 \mu_o} \qquad r_D = \frac{r}{r_w} \qquad t_{cD} = \frac{\alpha r_{cD}^2}{2.246\gamma}$$

$$\alpha = \frac{M_0 \mu_o (c_r + c_w)}{2\pi(1-S_r)H\rho_o k_r k} \qquad x = \frac{r_D^2}{t_D}$$

M_0 = mass injection rate [MT^{-1}]
t = time [T]
S_r = residual brine saturation [-]
ϕ = porosity [-]
μ_o = viscosity of CO_2 [$ML^{-1}T^{-1}$]
μ_w = viscosity of brine [$ML^{-1}T^{-1}$]
H = formation thickness [L]
r_w = well radius [L]
ρ_o = density of CO_2 [ML^{-3}]
k_r = end-point CO_2 relative permeability [-]
k = permeability [L^2]
p = pressure [$ML^{-1}T^{-2}$]
p_0 = initial pressure [$ML^{-1}T^{-2}$]
c_r = compressibility of formation [$M^{-1}LT^2$]
c_w = compressibility of brine [$M^{-1}LT^2$]
r_c = formation radius [L]

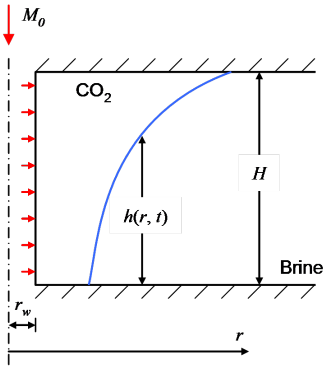

Figure 1: Schematic diagram of model.

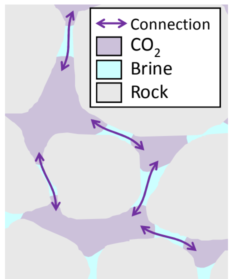

Figure 2: Schematic view of residual brine saturation.

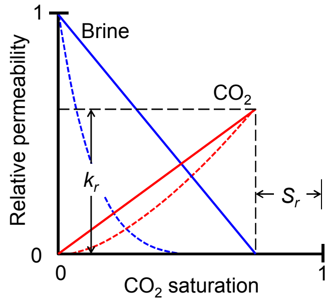

Figure 3: Relative permeability functions.

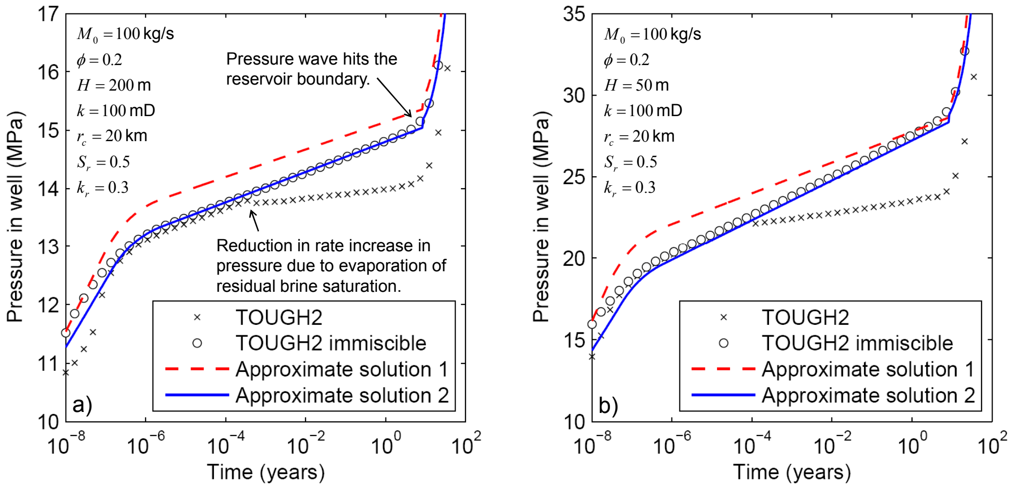

Figure 4: Comparison of the approximate solution with output from TOUGH2 ECO2N. Approximate solution 1 uses fluid properties based on the initial pressure. Approximate solution 2 uses fluid properties based on the pressure given by Approximate solution 1 at $t_D = t_{cD}$.

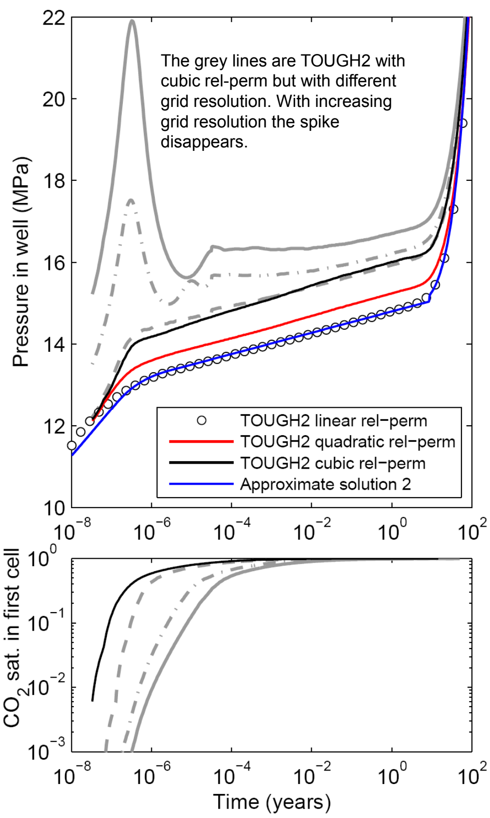

Figure 5: Same as Figure 3a but with non-linear relative permeability. Spike disappears with increasing grid resolution.

Conclusions

Vertical pressure gradients and capillary pressure were found not to significantly affect pressure buildup for the scenarios studied. Similarly, providing fluid properties for the end conditions are used, dynamic variability in fluid properties were also found to have negligible effect. Miscibility was found to reduce pressure due to brine evaporation. Non-linearity in relative permeability leads to increases pressure. A spike in pressure during early times was found to be due to numerical errors. But consideration of Figure 6 raises an interesting problem.

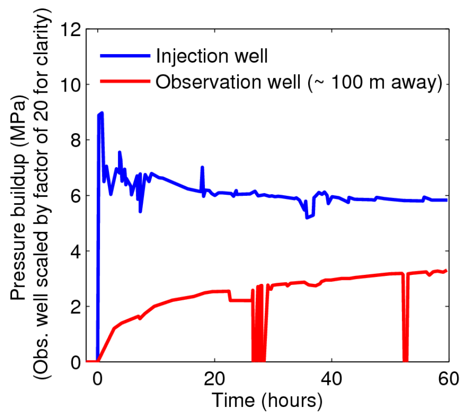

Figure 6: Observed pressure from a CO_2 project injecting at ~ 6 kg/s. (from S. Hovorka, BEG).

Further reading

Mathias, SA, Hardisty, PE, Trudell, MR & Zimmerman, RW 2009. Approximate Solutions for Pressure Buildup During CO_2 Injection in Brine Aquifers. Transport in Porous Media 79(2): 265-284.